Commonwealth of Massachusetts

Office of Consumer Affairs and Business Regulation

2000 Energy Efficiency Activities
A Report by the Division of Energy Resources

An Annual Report to the Great and General Court on the Status of Energy Efficiency Activities in Massachusetts

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Jane Swift
Governor

Jennifer Davis Carey
Director
Consumer Affairs and Business Regulation

David L. O'Connor
Commissioner
Division of Energy Resources

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The Division of Energy Resources Energy Efficiency Team prepared this report under the direction of Team Leader Bruce Ledgerwood. Readers may obtain additional information about the report from the Division at (617) 727-4732.

The following individuals made primary contributions to the report:

Julie Michals – Report writing, analysis of 2000 energy efficiency data
Lisa Glover – Compilation of 2000 energy efficiency data
Alvaro Pereira – Energy 2020, REMI analysis
Zazy Atallah – Energy 2020, REMI analysis
Michelle Moseley – Bill impact analysis

Editing and production assistance provided by Andrea Hattan and Karin Pisiewski.

Please feel free to convey to the contributors listed above your reaction to this report and your thoughts with respect to energy efficiency activities in the state.

This report, as well as a summary report, is posted on the Division's website at www.mass.gov/doer.

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1.0 Statewide Energy Efficiency Goal and Objectives

The Division of Energy Resources uses the Statewide Energy Efficiency Goal and Objectives as the basis for annually reporting to the Legislature on statewide energy efficiency activities (see Table 1). The overall Statewide Energy Efficiency Goal and its supporting objectives largely come from key provisions of the Electric Industry Restructuring Act [St. 1997, c. 164], or "the Act," as well as extensive stakeholder input.

Table 1: Massachusetts Energy Efficiency Goal and Objectives

Overall Statewide Energy Efficiency Goal: *Strengthen the economy and protect the environment by increasing the efficiency of energy use*
Energy Efficiency Operational Objectives: *(1) Reduce the use of electricity cost-effectively.* *(2) Ensure that energy efficiency funds are allocated to low-income customers consistent with the requirements of the Act, and allocated equitably to other customer classes.*
Energy Efficiency Programmatic Objectives: *(3) Reduce customer energy costs by balancing short-run and long-run savings from energy efficiency programs.* *(4) Support the development of competitive markets for energy efficiency products and services.*

The *overall statewide goal* of energy efficiency programs ("programs") is to strengthen the economy by reducing electricity costs to customers and to increase state employment and income, as well as to protect the environment by reducing harmful air emissions.

Two *operational objectives* of programs come largely from the Act. First, programs should be cost-effective (according to a methodology approved by the Department of Telecommunications and Energy). Second, funding levels for programs serving income eligible households should be the greater of 0.25 mills/kWh or 20 percent of the program funding level for all residential programs. Equitable allocation of program funds among customer sectors is a related goal of this objective. Equitable allocation means that the distribution of program expenditures to a customer sector is roughly equal to the funds collected from that customer sector. Further, the Division interprets this goal to require that residential and commercial and industrial (C&I) customer sectors equitably subsidize the low-income sector, to an extent deemed reasonable by the Division, the Program Administrators (i.e., distribution companies) and key stakeholders.

Programmatic objectives call for programs to provide immediate as well as long-term electricity cost reductions to customers using different program design and implementation strategies. In addition, programs should be designed to support the development of competitive markets for energy efficiency products and services.

2.0 Overall Goal: To Strengthen the Economy and Protect the Environment

2.1 Impact of Energy Efficiency Programs on the Commonwealth's Economy

The Overall Statewide Energy Efficiency goal acknowledges the critical role of energy in our Commonwealth's economy. Conserving electricity strengthens our economy by reducing energy bills. This section documents the benefits that accrued to program participants and those that accrued to all consumers as a result of energy efficiency related system benefits, as summarized in Table 2.

Table 2: Summary of 2000 Economic Impacts of Program Activities

Electricity Bill Impacts	
Energy Savings	
• Total Participant Annual Energy Savings	$19 million
• Average Life of Energy Efficiency Measures	15 years
• Total Participant Lifetime Energy Savings	$295 million
• Average Cost for Conserved Energy	4.1¢/kWh
Demand Savings	
• Total Participant Annual Demand Savings	$1.2 million
• Interruptible Service Credit Payments	$3.1 million
System Impacts	
Savings to All Customers Due to Lower Wholesale Energy Clearing Prices*	$5.7 million
Employment Impacts	
Number of New Jobs Created	1,183
Disposable Income from Net Employment	$48 million

* Cumulative 3-year impact (1998-2000) over June-September 2000 peak hours.
Source: Division of Energy Resources

2.1.1 Savings to Program Participants

Massachusetts consumers continued to face relatively high average electricity rates in 2000 compared to other states.[1] Energy efficiency program activities provided opportunities for participants to reduce bills by reducing electricity use, both in the short and long-term. This was achieved primarily through energy savings, and for some participants, through demand savings as well.

(a) Electricity Bill Savings Due to Energy (kWh) Savings

Energy savings represent electricity savings available to customers from decreases in kilowatt-hours (kWh) use. Energy savings can be described in two ways: *annual* savings and *lifetime*

[1] The average total electricity rate for Massachusetts customers in 2000 was 9.3¢ per kWh, compared to the national average of 6.7¢ per kWh. (Source: Market Monitor 2000, A Report by the Division of Energy Resources). Note that these rates do not reflect competitive retail supplier rates.

savings. Annual savings accrue in the year that energy efficiency measures are installed. Lifetime savings reflect the customer savings over the productive life of the energy conservation measures.

Table 3: Energy Savings from Energy Efficiency Programs (in million kWh)

Type of Savings	1998 Savings	1999 Savings	2000 Savings
Annual	263	272	273
Lifetime	3,417	3,822	4,147

Table 3 shows that annual energy savings for 2000 Programs were estimated at 273 million kWh[2], the equivalent of annual electricity use for 38,000 households[3]. Long-term energy savings resulting from 2000 equipment installations were estimated to be 4,147 million kWh over an average period of fifteen years.[4]

In order to estimate the average annual bill impacts resulting from 273 million kWh of energy savings in 2000, the Division analyzed program participation rates, average energy use per participant, and rate impacts for each customer sector specific to each distribution company service territory. Below, the Division first summarizes program participation rates in 2000, and then provides estimated annual bill savings.

(b) Program Participation

In general, total annual program participation increased by 1 percent in 2000, compared to 1999. Participation was highest for the Large C&I and Residential sector, followed by the Low-Income and Medium C&I sectors (see Table 4). Small C&I customers, and to a lesser extent Medium C&I customers, had the lowest participation rates despite potential bill savings and efforts to target these customers. Barriers these customers face to investing in energy efficiency, including a lack of energy management resources and interest in reducing energy use can explain these lower rates. However, the cumulative participation rate for Small and Medium C&I customers over the last decade is between 25-35 percent. Given the demonstrated savings these customers can achieve through energy efficiency (as discussed below), opportunities to target these sectors should be further explored.

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[2] All information in this report regarding savings, program expenditures, bill impacts etc. is aggregated across all Massachusetts electric distribution companies. For information specific to a distribution company, contact the Division.

[3] This assumes an average electricity use of 600 kWh per month per household.

[4] Lifetime energy savings increased by 8.5 percent from 1999 to 2000, while annual savings were roughly the same. This increase in lifetime savings was due to an increase in average measure life from 14 to 15 years. This change is likely due to a combination of factors including a greater number of fixture installations (which have a longer life than compact fluorescent bulbs), and recent "persistent" studies that show technologies remain in place in facilities/buildings longer than earlier forecasted, partly due to improved durability of certain technologies.

Table 4: 2000 and Cumulative Program Participation[5]

Customer Sector	Total Customers In 2000	Number of Participants in 2000	Percent Served in 2000	Cumulative Participation Since 1989
Low-Income	571,227	27,791	5	n/a
Residential	1,529,044	188,553	12	60
Small C&I	239,791	2,144	1	25-35
Medium C&I	60,425	1,525	3	25-35
Large C&I	5,715	660	12	50-60
Total/Average	**2,406,203**	**220,673**	**9**	**45**

Source: Division of Energy Resources - Compilation of 2000 Program Statistics Reported by Program Administrators

(c) Annual Electricity Bill Savings

The Division estimated average bill impacts (from energy savings only) for participating customers based on rate class tariff data and program participation levels. Table 5 summarizes the following key findings:

- Total annual bill reductions for all participating customers from program savings;
- Average annual bill per participant;
- Average annual bill savings per participant; and
- Corresponding average annual bill reduction as a percent of the average participant's annual electricity bill.

Table 5: 2000 Average Bill Impacts From Energy Savings

Customer Class	Total Annual Bill Reductions for Participants	Avg. Annual Bill Savings per Participant	Avg. Annual Bill per Participant	Avg. Savings As a Percent of Avg. Annual Bill
Low-Income	$ 983,045	$78	$557	14
Residential	$ 5,563,663	$32	$737	4
Small C&I	$ 1,557,061	$726	$7,842	9
Medium C&I	$ 2,408,230	$1,579	$27,068	6
Large C&I	$ 8,676,129	$13,146	$270,832	5
Total/Average	**$19,188,129**	**$100**	**$1,804**	**5**

Source: Division of Energy Resources' Bill Impact Analysis

Program participants saved over $19 million in direct electricity costs in 2000. The largest percent savings were for Low-Income participants at an average of 14 percent based on an

[5] For this report, C&I rate classes were aggregated and categorized into Small, Medium and Large C&I sub-sectors. Small C&I includes rate classes with average monthly use of less than or equal to 3,000 kWh/month. Medium C&I includes rate classes with average monthly use greater than 3,000 kWh/month, but less than or equal to 120,000 kWh/month. Large C&I includes rate classes with average monthly use greater than 120,000 kWh/month.

average annual bill of $557.[6] This level of savings for Low-Income households shows that these participants greatly benefited from the energy efficiency programs administered by the Low-Income Affordable Energy Network and coordinated with the Program Administrators. Spending on Low-Income programs also increased nearly 30 percent relative to the previous year, partly explaining the high average level of savings per participant. Residential customers saved an average of 4 percent on their annual bill, similar to savings in previous years.

For the Small C&I sector, average savings per participant were $726 annually, with total savings over $1.5 million. These savings represent roughly 9 percent savings on the average annual participant bill. Given these demonstrated savings, opportunities to target this sector should continue despite barriers these customers face to investing in energy efficiency. The Medium and Large C&I participants reduced their average annual bills by an average of 6 and 5 percent, respectively, substantial increases for both sectors over 1999 bill savings. It is important to note that for these customer sectors, the range of savings across energy efficiency projects can be considerable (e.g., as high as 10 percent of annual electricity costs) depending on the scope of the project.

(d) Long-Term Electricity Bill Savings

Table 5 presents only the *annual* bill impacts due to energy savings from the 2000 Programs. Over the productive *lifetime* that the equipment remains in place – an average of 15 years – total savings are projected to grow to approximately $295 million for participating customers.

Another way to quantify the impact of energy savings from 2000 Program activities is to compare program costs and energy saved over time (i.e., the cost of conserved energy), to the projected average retail electricity price over roughly the same period. A total investment of $168 million was made in 2000 for higher efficient equipment through the Programs.[7] These investments are projected to produce lifetime energy savings of 4,147 million kWh, translating to an average cost for conserved energy of 4.1¢/kWh[8] – 55 percent less expensive than the projected average retail price (9.25¢/kWh) over the same period.[9]

(e) Electricity Bill Savings Due to Demand (KW) Reductions

Demand savings represent the impact that the energy efficiency programs have on reducing demand (in kilowatts or KW) on the electricity system during very high or "peak" periods, when electricity is most expensive. Customers that participated in the Programs, and that had a

[6] Note that the bill impacts in Table 5 for the Low-Income participants reflect only those customers that are on a discounted rate, and therefore do not reflect all Low-Income participants at or below 200% of the Federal Poverty Level. As such, the participation levels implicit in Table 5 for the Low-Income and Residential sectors are not consistent with participation levels provided in Table 4.

[7] This $168 million includes 2000 energy efficiency expenditures funded through the mandated ratepayer energy efficiency charge of $130.5 million, plus participant costs of $38 million.

[8] For 2000, the average cost of conserved energy is calculated as the total ratepayer funded energy efficiency expenditures plus participant costs ($130.5 million and $38 million, respectively) divided by projected lifetime energy savings (4,147 million kWh) due to energy efficiency measures installed in 2000.

[9] Source: The Division of Energy Resources - Energy 2020 Model. This average retail electricity price (in 2000$) reflects prices over the average productive life of the energy efficiency measures installed in 2000, and includes all components of electricity price (e.g., generation, transmission, distribution and customer charges).

demand charge component on their electricity bills, saved money directly by reducing their electricity demand.

In 2000, Programs resulted in 88 MW of demand savings[10], representing 1 percent of the distribution companies' combined summer coincident peak demand of 8,343 MW. Roughly half of these savings was attributable to load management programs, primarily C&I interruptible service programs.[11] In 2000, participating C&I customers received $3.1 million in interruptible service credits. While interruptible credit programs play an important role in reducing demand on the electric system, the Division, with other key stakeholders, has directed Program Administrators that offer these programs to discontinue funding them through the ratepayer-funded energy efficiency charge. Rather, the Division views the development of a market-based demand-bidding program at the New England Independent System Operator (NE-ISO) as a more appropriate venue for reducing demand on the system. Further, to the extent distribution companies determine there is a continued need to reduce demand through "traditional" type interruptible credit type programs (e.g., in order to help maintain service reliability for generation, transmission and distribution), the Division believes these programs should be funded through sources other than the energy efficiency charge.

The balance of demand savings was provided through end-use savings to both Residential and C&I customers. A portion of these savings[12] provided direct savings during peak summer and winter to participating customers that have a demand charge component on their electricity bill, primarily Medium and Large C&I customers. The Division estimates these savings to be roughly $1.2 million annually for participating customers with demand charges. These demand savings will persist over the productive life of the energy efficiency measures installed in 2000, thus benefiting the participants over the long-term.

2.1.2 Electric System Benefits

In addition to the direct economic benefits program participants received, the 2000 Programs provided system-wide benefits to all customers by:

- Reducing wholesale energy clearing prices
- Enhancing generating system reliability during peak usage periods
- Enhancing reliability of local transmission and distribution networks

(a) Reducing Wholesale Energy Clearing Prices

Historically, energy efficiency programs have postponed the need to build new power plants by reducing the growth of electricity demand and reducing the usage of existing power plants. Since the inception of programs in 1989, distribution companies have estimated the monetary value of reducing electricity demand for the purposes of determining program cost-

[10] These KW savings are based on combined company summer coincident peak demand savings reported by the Program Administrators. Annual winter KW savings for all distribution companies were 103 MW.
[11] Interruptible programs are programs in which large C&I customers agree to reduce their electricity load when called upon by their distribution company during capacity shortage or emergency situations.
[12] These savings, or nearly 16 MW, reflect the weighted average peak demand savings over summer and winter months. See Appendix A.

effectiveness.[13] This valuation focuses on the system impact of programs over the *long-term* (i.e., the lifetime of the measures installed). An additional way to value the demand reduction impact of energy efficiency programs is to consider their *short-term* impact. As a consequence of the new competitive wholesale electricity market and transparent prices, the value of demand reductions can be estimated in terms of how they help avoid costs of generating electricity on the margin, thus reducing market-clearing prices. Since the market-clearing price for electricity is a function of overall system supply and demand, individual customer demand reductions help reduce this price, thus providing monetary benefits to all customers in the region. Given the availability of hourly market-clearing price data tracked by the Independent System Operation of New England (ISO-NE), it is possible to roughly estimate the short-term (e.g., hourly, monthly, summer, etc.) price impacts of energy efficiency programs.

Procurement of Electricity in the Competitive Wholesale Market in New England

Under the current competitive market structure at ISO-NE, electricity from power plants is procured in order of increasing bids. The market-clearing price paid to all bidding power plant owners that are dispatched is set by the last, highest bid when the demand for electricity is met (e.g., in a particular hour). When energy efficiency programs lower demand for electricity in any given hour, they may displace the need for generation from this last bidder. In that case, the next highest bidder is the one that sets the market-clearing price. By eliminating the need for the last, highest bid, a lower clearing price is paid to all generators. This lower clearing price accrues to all customers in the form of lower wholesale (and ultimately retail) prices. These savings are a benefit over and above the direct savings that accrue to those customers who participate in the energy efficiency programs.

These avoided costs are modest for most hours but can be dramatic during peak hours when electricity is most expensive. The summer of 2000 illustrates the effect of energy efficiency program related demand reductions on electricity prices. It is estimated that ISO-NE system loads were reduced by an average of 72 MW across all hours as a result of efficiency programs. The system recorded its peak summer load on June 27th, where the average price during the peak hours (8am to 9pm) of this day was $92. Absent the demand reductions, the average peak demand may have been higher, resulting in higher bid prices setting the market-clearing price in each hour. Specifically, the average market-clearing price over the 13-hour period might have been 11 percent higher than the average market clearing price without the 72 MW demand savings from Programs.[14] The Division estimates that this impact may have avoided roughly $393,000 in additional costs to the system (i.e., to all buyers in the ISO-NE energy market and indirectly to customers) over the 13-hour period analyzed as shown in Figure 1.[15]

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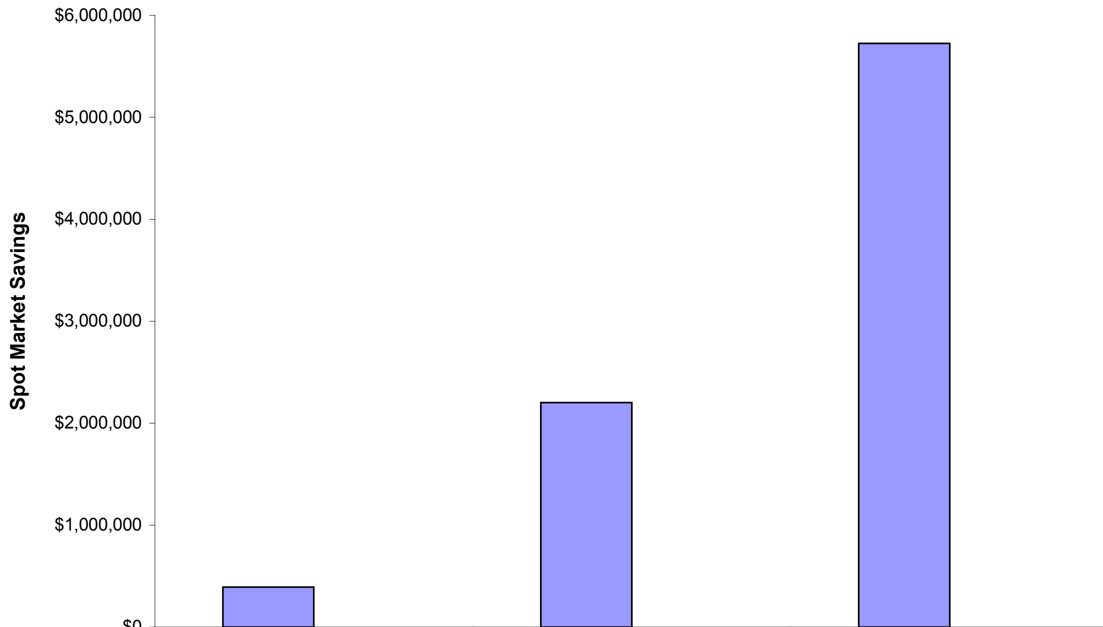
[13] The methodology used to value energy efficiency programs is based on estimates of avoided costs for generating energy, capacity, and avoided transmission and distribution costs. See discussion on cost-effectiveness in Section 4.0.

[14] The Division's analysis used theoretical cooling load shapes to put different utility peak reduction estimates on commensurate basis and estimated an aggregate variable hourly load reduction over ISO-NE peak hours for summer, 2000. See Appendix B for further detail.

[15] Avoided costs are based on spot market load (i.e., what was traded in the spot market in each hour), as opposed to total load (most of which is traded through bilateral contracts). Across summer, 2000 peak hours, the spot market represents 23% of system load. This avoided cost to the system is significantly lower than the potential value estimated by the Division for June 7th, 1999, as documented in its 1999 Energy Efficiency Report to the Legislature. Due to relatively milder conditions during summer 2000, and a lack of capacity shortages, the sizeable one-day price reductions experienced on June 7th, 1999 were unlikely to occur. Nevertheless, despite the lack of extreme load conditions, price reductions were still realized.

Figure 1. Potential Impact of Demand Reductions on Energy Spot Market



	ISO-NE Peak Hours (8am to 9pm, June 27, 2000)	Peak Hours Over the Full Summer (June-September, 2000)	Cumulative 3 Year Impact in 2000, Peak Hours Over the Full Summer (June-September, 2000)
Spot Market Savings	$393,483	$2,202,894	$5,724,291
Avg. Reduction (MW)	72	48	167

Furthermore, Figure 1 illustrates that the impact of demand reductions is not limited to days with unexpected high demand. Extending the analysis to all peak hours for the summer months June through September indicates that relatively small price changes spread over many hours add up to significant savings (roughly $2.2 million), where average demand reductions totaled 48 MW.

The cumulative impact of demand reductions is also significant. For example, if peak load reductions due to 1998 and 1999 energy conservation measure installations are added to the analysis of 2000 price impacts (with one-time interruptible program reductions removed) the estimated reduction rises to 167 MW. A reduction of this magnitude during the summer of 2000 increases the avoided costs to nearly $6 million on spot market load alone.

Finally, all of these estimated demand savings are based on the limited load in the spot energy market. Over time, however, there is an additional impact on the remainder of the energy market operating on bilateral contracts. Bilateral market prices directly depend on spot energy prices, as is the general case in other commodity markets.[16] Thus, the impact of demand savings on the bilateral contract energy market would increase savings significantly.

[16] Patton, David B. 2001. An Assessment of Peak Energy Pricing In New England During Summer 2001. www.ISO-NE.com, page 50. While bilateral contract prices are set well in advance, especially for most retail

It is important to note that this analysis is subject to a degree of uncertainty. Specifically, the day-ahead price bids, on which this analysis is based, only approximate the actual day-of supply curve.[17] A recent analysis performed for ISO-NE indicates that estimates of price difference based on the day-ahead bidstack are fundamentally conservative.[18] The Division, therefore, understates the impact that energy efficiency programs had on reducing energy clearing prices in 2000.

Further, the scope of the Division's analysis is conservative in two other ways: first, the Division's analysis focused only on Massachusetts, and did not include the impacts of demand reductions from ratepayer-funded energy efficiency activities in other New England states. Second, by reducing energy use during peak periods, energy efficiency efforts help displace the need to run generation plants at the margin, which tend to be higher polluting plants. While the Division does not estimate the monetary value of reduced emissions, the Division recognizes this as a societal benefit. A discussion of environmental impacts is discussed further in Section 3 below.

(b) Increasing System Reliability

By reducing demand, Programs contribute to system reliability in terms of supply adequacy within a particular area or region. Their contribution depends on the technologies targeted. High efficiency lighting and refrigeration, for example, reduce base load, while more efficient air conditioners and chillers help reduce summer time peak load. All energy efficiency measures, however, help maintain adequate margins of generation supply, and can help deter brownouts and blackouts.

(c) Increasing Reliability of Local Transmission and Distribution Networks

A third system benefit of energy efficiency programs is enhanced reliability of local transmission and distribution (T&D) networks. This is especially important in Massachusetts where there is constrained transmission into the Boston area and the Cape and Islands. By reducing load and demand on the power distribution network, the Programs decrease the costly likelihood of failures. Over the long-term, energy efficiency programs can postpone the need for additional

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customers, they reflect the basic supply and demand relationship in the overall system. The energy efficiency program related demand reductions and related price effect are reflected in future contracts by reducing the spot prices to which the prices in many of those contracts are linked, and by reducing risk premiums that are generally based on price volatility, and additional costs avoided at that point.

[17] There is substantial inherent uncertainty as to the actual generator that would have been setting the energy clearing price (ECP) on the margin if the system load had been higher (that is, without the impact of the state's energy efficiency programs). This is primarily due to the fact that some generators, after submitting their price bids on one day, may become unavailable to run on the next day, so that a different generating plant, having bid a different price, may actually be dispatched to meet load (thereby setting the ECP) in any particular hour.

[18] Patton, David B. 2001. An Assessment of Peak Energy Pricing In New England During Summer 2001. www.ISO-NE.com. In his analysis, Patton studied how the slope of the day-ahead bidstack changes in the real time supply curve. He identified four different ways that market rules adjust the shape of a day ahead bid stack, and that the combination of these shifts can only increase the overall slope of the supply curve relative to the day-ahead bidstack. (pp.5-15).

transmission lines and transformers, thus delaying upgrade costs for T&D paid by all customers.

In conclusion, the Division believes significant opportunities exist in Massachusetts to reduce summer peak demand through energy efficiency programs that provide system-wide benefits to all customers in the three key areas discussed above. This can be done by a) focusing on installing higher efficiency air conditioning and chiller units prior to summer for Residential and C&I customers; b) promoting higher efficiency standards for air conditioning equipment; and c) targeting C&I recommissioning opportunities. The Division is working with Program Administrators and key stakeholders to address these opportunities.

2.1.3 Economic Development Impacts

Economic development impacts of 2000 Programs are visible in two forms: job creation in the energy efficiency industry and other industries in Massachusetts, and direct savings to C&I customers for capital reinvestment and/or competitive improvements.

The Division examined employment impacts using the Regional Economic Model (REMI). The Division estimates that 2000 Program expenditures (plus associated participant costs) added 1,183 new jobs to the Massachusetts economy in 2000. The majority of jobs were created in the services industry (47 percent), following by manufacturing (14 percent), retail trade (12 percent), construction (9 percent), and wholesale trade (8 percent). These new jobs added $73 million to the gross state product, including $48 million in disposable income in 2000 alone. The 1,183 jobs created in 2000 will persist, but at a decreasing rate, over more than decade.[19] These positive economic impacts of energy efficiency programs are consistent with results from studies performed in other states, including analyses in Iowa and Illinois, as well as a combined study in New York, New Jersey and Pennsylvania.[20]

Summary: Overall Goal – To Strengthen the Economy

The Division concludes that 2000 Programs produced net gains for participants and the Commonwealth. Customers reduced their annual bills, and will continue to benefit over the lifetime of the conservation measures installed in their facility or home. This, in effect, increased customers' discretionary spending, with corresponding benefits to the state economy. Moreover, analysis of benefits to the entire New England electricity system demonstrate that energy efficiency activities can play an important role in helping to reduce market clearing prices and increasing system reliability. The Division will work closely with Program Administrators and key stakeholders to identify further opportunities for bringing these types of benefits to all customers through Program activities.

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[19] See Appendix C for a description of the Division's job impact analysis.

[20] These studies are: Weisbrod, Glen, Hagler Bailly Consulting Inc, et al, *Final Report: The Economic Impact of Energy Efficiency Programs and Renewable Power for Iowa,* Prepared for the Iowa Department of Natural Resources, December 1995; Goldberg, Marshall et al, *Energy Efficiency and Economic Development in Illinois,* American Council for an Energy-Efficient Economy (ACEEE), December 1998; and Nadel, Steven et al, *Energy Efficiency and Economic Development in New York, New Jersey and Pennsylvania,* ACEEE, February 1997.

2.2 Impact of Energy Efficiency Programs on Reducing Power Plant Emissions

The overall Statewide Energy Efficiency Goal also acknowledges the detrimental environmental effects of electricity generation. By reducing electricity consumption, energy efficiency programs can help reduce emissions caused by fossil fuel combustion used to generate electricity. In 2000, about 63 percent of all electricity generation in New England came from fossil-fueled generation plants. The environmental consequences of emissions from such plants include acid rain, ground-level ozone (smog), and climate change.

2.2.1 2000 Emission Reduction Impacts

The Division analyzed the impact of energy efficiency programs on reducing annual emissions due to 2000 installations alone, as well as the impact of emissions reductions over the lifetime (15 years) of measures installed in 2000. Table 6 provides a summary of these impacts for the primary pollutants: sulfur dioxide (SO_2), nitrogen oxides (NO_x), and carbon dioxide (CO_2). See Appendix D for a description of the Division's emission reduction analysis.

Table 6: Impact of 2000 Programs on Reducing Emissions in New England

Pollutant	Environmental/Health Impact	Avoided Emissions (in tons)	
		Year 2000 Only	2000 Lifetime of Measures
Nitrogen Oxides (NO_X)	Smog (respiratory health damage) and acid rain (damage to natural habitats, etc.)	705	6,558
Sulfur Dioxide (SO_2)	Acid rain (damage to natural habitats, etc.) and acid aerosols (asthma & other respiratory health damage)	1,405	9,086
Carbon Dioxide (CO_2)	Global warming (climate change, with more extreme weather events, rising sea level, economic disruption, etc.)	253,100	2,042,400

Source: Division of Energy Resources – Energy 2020 Model Analysis

To provide more comprehensible reference points for the tons of avoided emissions listed in Table 6, the Division estimates the following:

- Emitting 705 fewer tons of NO_x from power plants is equivalent to removing more than 53,410 automobiles from New England roads of in 2000.[21]

- Emitting 1,405 fewer tons of SO_2 (if all were from coal burning power plants) is equivalent to burning 100,030 fewer tons of coal in New England.[22]

- Emitting 253,100 fewer tons of CO_2 is comparable to removing about 50,855 automobiles and other light vehicles from the roads.[23]

It is important to note that the Division's estimates of reduced emissions in year 2000 are conservative in that they reflect the impact of measures installed in year 2000 alone. They do not reflect the impact of energy efficiency measures installed in years prior to 2000, but that were still in place in 2000, thus helping to reduce emissions.

Finally, the Division estimates that emission reductions for NO_x, SO_2, and CO_2 over the lifetime of energy efficiency measures (an average of 15 years) installed in 2000 will be 6,558 tons, 9,086 tons, and 2,042,400 tons, respectively. Thus, the air quality benefits from 2000 energy efficiency activities will continue over the long term.

Summary: Overall Goal – To Protect the Environment

There are many strategies – both regulatory and market-based – that can be used to combat the negative air quality effects of electricity generation. These include federal (e.g., Environmental Protection Agency and the Clean Air Act), regional (e.g., Northeast States Coordinated Air Use Management and the Ozone Transport Committee), and state regulatory efforts. Market-based

[21] The NO_x equivalence is based on 1.0 grams of NOx emitted per mile for light duty vehicles (automobiles—not SUVs, vans, or pick-up trucks) and 12,000 miles per year per average vehicle (personal communication from the MA Department of Environmental Protection [DEP], January 2000).
[22] The SO_2 equivalence is based on 71.2 tons of coal per ton of SO_2, based on 1998 data from the Energy Information Agency's 1998 *Electric Power Annual*, Vol. 1, Tables 14 (8,136 thousand tons of coal burned by New England power plants) at http://www.eia.doe.gov/cneaf/electricity/epav1/ta14p1.html, and the EPA's "Emissions Scorecard 1998," Table B3 (114,275 tons of SO_2 emitted from New England coal burning power plants) at http://www.epa.gov/airmarkets/emissions/score98/tavble_b3.xls.
[23] The CO_2 equivalence is based on 4.9767 tons of CO_2 emitted per vehicle per year, based on 1998 Massachusetts gasoline consumption data (per the MA DEP), the total number of gasoline vehicles registered in Massachusetts in 1998 (per the MA Department of Motor Vehicles via the MA DEP), and US EPA methodology.

programs include tradable allowances for SO_2 and NO_X, and voluntary programs promoting energy efficiency and renewable energy. Energy efficiency programs play an important and complementary role in this larger context of environmental protection by improving air quality in the state and the New England region.

3.0 Program Cost-Effectiveness Objective

The Act requires that ratepayer-funded energy efficiency programs meet cost-effectiveness criteria defined by the Department of Telecommunications and Energy (the Department). The Department's required methodology compares the benefits and costs of each program and calculates a benefit-cost ratio. A program benefit-cost ratio of 1.0 or higher is considered cost-effective under the methodology.

3.1 Cost-Effectiveness Methodologies

Prior to year 2000, Program Administrators used several tests to evaluate programs. These methodologies included the electric system test (or utility test), the total resource cost test, and the societal test. The tests differ in how they define benefits and costs and from which perspective (i.e., that of the distribution company, and/or the participating customer, and/or society as a whole) one views the benefits and costs, as described below.

Overview of Key Cost-effectiveness Test Methodologies

Electric System Test - The Electric System Test (EST) considers benefits and costs to the electric system as a result of the energy efficiency programs, and is used to ensure that electric ratepayers receive net benefits from the energy efficiency programs they fund. Benefits include the value of avoided wholesale electricity costs, as well as avoided transmission and distribution costs to the distribution company that otherwise would be passed on to ratepayers. The denominator of the cost-effectiveness ratio using the EST is simply annual energy efficiency program costs funded by ratepayers, and does not include participant costs.

Total Resource Cost Test – The Total Resource Cost Test (TRC) considers a broader set of benefits and costs than the Electric System Test, including the direct benefits and costs to the participating customers. Specifically, benefits extend to quantifiable benefits that accrue to participating customers such as the impact that energy efficiency equipment has on avoiding other energy costs as well as non-energy costs (e.g., reduced gas bills, increased worker productivity, decreased operating and maintenance costs). Costs extent beyond just program costs paid by ratepayer energy efficiency funds, and include the direct investment made by the customers that participate in the programs. For example, while a program may cover 75% of the incremental cost of installing more efficient equipment over standard equipment, a customer pays the balance of this incremental cost, known as the "participant cost." The TRC test is basically the Societal Test without externalities (see below), and is the test required by the Department in its 98-100 Order.

Societal Test – The Societal Cost Test is structurally similar to the TRC test, yet it goes beyond the TRC test in that it attempts to quantify total resource costs to society as a whole rather than to only the utility service territory (i.e., the distribution company and its ratepayers). In taking a broader perspective, the Societal Cost Test utilizes essentially the same cost variables as the TRC test, but has a greater scope of benefits that are defined with a societal point of view. Examples of societal benefits from avoided electric generation can include reduced emissions of sulfur dioxide, nitrous oxide and particulates from power plants.

3.2 2000 Program Cost-Effectiveness

Starting in 2000, pursuant to the Department's 98-100 Order and Guidelines, Program Administrators screened their programs using the Total Resource Cost test, thus broadening the range of quantifiable benefits used to assess the cost-effectiveness of their programs. As a result, the cost-effectiveness of programs in 2000 improved considerably compared to 1999. Specifically, in 2000, a total of $317 million in benefits exceeded the $163 million in costs[24] for a net benefit of $154 million. Thus, programs were cost-effective with an overall benefit-cost ratio of almost 2 to 1 (compared to 1.6 to 1 in 1999). Benefit-cost ratios for the Low-Income, Residential and C&I programs are provided in Table 7.

The additional benefits counted under the Total Resource Cost test specifically impacted the cost-effectiveness of the Low-Income and Residential programs. These benefits include increased property improvement for homeowners due to the installation of higher efficiency equipment. In addition, energy efficiency investments save distribution companies money by reducing costs related to bad debt expenses, and termination and connection charges-costs that would otherwise be passed on to all customers. The value of these added benefits largely explains the nearly three-fold increase in the benefit-cost ratio for the Low-Income programs, from 0.9 in 1999 to 2.6 in 2000. Customers also accrue resource savings in reduced natural gas and water bills. For example, the investment in an energy efficient clothes washer will not only reduce electricity costs to wash the clothes, but will also reduce water use and if applicable, the gas used to heat the water. These added benefits help to explain the increase in Residential program cost-effectiveness, from 1.1 in 1999 to 1.5 in 2000.

For the C&I sector, program cost-effectiveness remained relatively unchanged in 2000 compared to 1999, where the benefit-cost ratio increased from 1.9 to 2.0. While the Department's 98-100 Order and Guidelines allow for the counting of increased worker productivity and property improvement for businesses due to the installation of higher efficiency equipment, these values can be difficult to estimate. Nonetheless, C&I programs remain more cost-effective than Residential programs, primarily because C&I customers can take advantage of economies of scale (i.e., their costs to purchase and install energy efficiency measures are less per unit). Further, electricity is used by C&I customers for a greater proportion of each day, thus greater savings can be reaped from more frequent use of energy conservation measures.

Table 7. 2000 Program Cost-Effectiveness

	Benefit-Cost Ratio	
Customer Class	**Without PPE***	**With PPE***
Low-Income	2.6	2.6
Residential	1.5	2.3
C&I	2.0	2.3
Total	**1.9**	**2.4**

* PPE = post program effects

The Department's 98-100 Order and Guidelines also directed Program Administrators, for the first time, to report on post-program effects associated with market transformation programs (see Section 6.1). Post-program effects (i.e., savings) are a direct result of the programs that accrue to customers, not just participants, *after* the programs have ended. Although the estimates of these

[24] These costs include participant costs but exclude costs associated Integrated Resource Management (IRM) programs based on Department-approved accounting/reporting methodology for the IRM savings and costs.

post-program effects are less certain than savings associated with traditional programs, they provide a good indication of the savings magnitude of market transformation programs. The Division calculates that the overall cost-effectiveness of 2000 programs was more than 25 percent higher – or a benefit-cost ratio of 2.4 – with the inclusion of post-program effects. Given the post-market effect estimates are considered rough, the Department plans to test the accuracy of these forecasts in the near future.

Summary: Program Cost-Effectiveness Objective

The cost-effectiveness of year 2000 programs was marked with the application of the Department's newly revised methodology. Pursuant to the Department's 98-100 Order and Guidelines, all programs were cost-effective for all customer sectors. Moreover, the cost-effectiveness of the Low-Income programs, and to a lesser extent the Residential programs, increased significantly compared to prior years as a result of counting a broader range of benefits and costs associated with energy efficiency programs. Furthermore, the Department's 98-100 Order and Guidelines provided a necessary framework for valuing post-program effects associated with market transformation programs – a fundamental step to capturing the full benefits of these types of programs, as discussed in Section 6.

4.0 Equitable Allocation of Funds Objective

The Act directs the Division to ensure that Program activities are equitably allocated among customer sectors. Absent an explicit definition provided by the Act, the Division interprets "equitable allocation" to mean that the amount of funds collected from a specific customer sector should ideally be expended on that sector, but that circumstances may not always warrant such proportional allocation.[25] However, judgement as to whether funds are equitably allocated is influenced by specific requirements set forth in the Act. The Legislature, acknowledging that Low-Income households are not likely to be served by the competitive energy market, directed funding levels for Low-Income programs to be no less than the greater of 0.25 mills per all kWh sold by electric distribution companies or 20 percent of the total residential budget. Therefore, a minimum portion of collected funds is allocated to this customer sector, and if necessary, should be subsidized equitably by funds collected from the Residential and C&I sectors.[26] For the purposes of this analysis, the Division uses the federal weatherization program standard of 200 percent of the Federal Poverty Level to define the Low-Income population. The Division's analysis herein considers total funds available in 2000 for different customer sectors, and compares them to expenditures (plus year-end fund balances) for each sector.

4.1 2000 Total Available Funds

The funds available in 2000 to support Program activities included 1999 carryover funds plus interest and 2000 ratepayer collections based on the mandated charge of 2.85 mills per kWh sales. Table 8 summarizes the funds available by customer sector. Total available funds in 2000 were $152.4 million ($25.8 million in 1999 carryover funds and $126.6 million in 2000 collections).

Table 8: 2000 Total Available Funds

Customer Sector	1999 Carryover		2000 Collections		Total Available Funds	
	million $	percent	million $	percent	million $	percent
Low-Income	1.5	6	9.1	7	10.6	7
Residential	12.4	48	36.4	29	48.8	32
C&I	11.9	46	81.1	64	93.0	61
Total	**25.8**	**100**	**126.6**	**100**	**152.4**	**100**

Source: Division of Energy Resources – Compilation of 2000 Program Statistics Reported by Program Administrators.
Note: Percent totals may not add up due to rounding.

[25] A strictly proportional allocation of funds (i.e., $1 collected from a customer sector is allocated to same customer sector) could cause Program Administrators to forgo inequitable investment opportunities that significantly lower system costs, thus benefiting all customers. Furthermore, due to the vagaries of program implementation, exact allocations would be a goal that would be difficult to implement since many implementation activities are beyond the control of the Program Administrators (e.g., vendors become behind schedule, customers do not respond to marketing, etc.) Also, program plans are often altered significantly before they become actual program expenditures.

[26] See Division's Energy Efficiency Oversight Guidelines supporting its regulation 225 CMR 11.0.

Total 2000 collections represented roughly 3 percent of customers' average annual electricity charges. The availability of funds for the C&I, Residential and Low-Income sectors were 61, 32, and 7 percent, respectively.

4.2 2000 Expenditures and Year-End Fund Balance

Given that Total Available Funds were $152.4 million in 2000, and Expenditures totaled $130.5 million, Table 9 shows a $21.9 million year-end fund balance that was carried forward to 2001. Note that expenditures reported include all 2000 energy efficiency expenditures, including administration, marketing, program implementation, program evaluation and performance incentives paid to the Program Administrators.

Table 9: 2000 Expenditures and Fund Balance

Customer Sector	2000 Expenditures		2000 Fund Balance		Expenditures Plus Fund Balance	
	million $	Percent	million $	percent	million $	percent
Low-Income	14.4	11	2.7	12	17.1	11
Residential	30.2	23	9.9	45	40.1	26
C&I	85.9	66	9.3	43	95.2	63
Total	**130.5**	**100**	**21.9**	**100**	**152.4**	**100**

Source: Division of Energy Resources – Compilation of 2000 Program Statistics Reported by Program Administrators.
Note: Percent totals may not add up due to rounding.

There are three main reasons for the year-end carryover. First, over half of this year-end balance represented committed payments set-aside for future payment of performance contracts.[27] Second, actual sales were higher than forecasted sales (which were used to develop program budgets), thus producing a surplus of funds. Third, portion of 2000 funds was committed to energy efficiency projects, but not yet expended as of year-end 2000. Unexpended funds in 2000, plus interest, were carried forward to 2001. The Division anticipates that the 2000 fund balance and year-end balances for 2001 and 2002 will be fully committed to specific energy efficiency projects by year-end 2002.

The largest portion of 2000 expenditures was spent on the C&I sector (66 percent), followed by the Residential and Low-Income sectors at 23 and 11 percent, respectively. The year-end fund balance for 2000 was 21.9 million, most of which was for the C&I and Residential sectors, followed by the Low-Income sector.[28] The allocation of Total Expenditures Plus Fund Balance was 63 percent to the C&I sector, 26 percent to the Residential sector, and 11 percent to the Low-Income sector. These are the values that the Division compares to the percentage breakout of Total Available Funds to analyze equitable allocation, as discussed below.

[27] These performance contracts are Integrated Resource Management (IRM) program related.
[28] The 2000 year-end fund balances for each customer sector are based on actual balances reported in the modified 2001 Energy Efficiency Plans filed by the Program Administrators.

4.3 Equitable Allocation Analysis

In reporting on whether Total Available Funds were allocated equitably to the different customer sectors in 2000, the Division looked at both Expenditures as well as Expenditures Plus Fund Balance at year-end for each customer sector. The latter provides the more accurate representation of whether funds were allocated equitably relative to Total Available Funds. For example, while actual expenditures in 2000 may not have been equitably expended due to various reasons, equitability may have been preserved if an appropriate amount of funds at year end was carried forward to the following year's budget and used for the same customer sector.

Table 10 compares 2000 Total Available Funds to Expenditures Plus Fund Balance in dollar and percentage terms.

Table 10: Comparison of 2000 Total Available Funds to Expenditures Plus Fund Balance

Customer Sector	2000 Total Available Funds		2000 Expenditures + Fund Balance	
	million $	Percent	million $	percent
Low-Income	10.6	7	17.1	11
Residential	48.8	32	40.1	26
C&I	93.0	61	95.2	63
Total	**152.4**	**100**	**152.4**	**100**

Source: Division of Energy Resources – Compilation of 2000 Program Statistics Reported by Program Administrators.
Note: Percent totals may not add up due to rounding.

For the Low-Income sector, a comparison of Total Available Funds in percentage terms (7 percent) versus Expenditures Plus Fund Balance (11 percent) suggests that a significant portion of Low-Income expenditures were subsidized. For the C&I sector, Total Available Funds in percentage terms (61 percent) was lower than Expenditures Plus Fund Balance (63 percent), indicating that this sector was slightly subsidized. The Residential sector subsidized both the Low-Income and C&I sectors, based on the fact that its Expenditures Plus Fund Balance (26 percent) was 6 percent less than Total Available Funds (32 percent).

While a certain level of subsidy towards the Low-Income sector is appropriate given mandated funding levels for the Low-Income sector, the fact that the C&I sector did not contribute to the Low-Income sector at all, and further was subsidized by Residential sector, raises equity concerns. The Division intends to work with Program Administrators and key stakeholders to ensure that in the future, funds between these two sectors are more equitably allocated.

Summary: Equitable Allocation of Funds Objective

The Division observes that the C&I sector did not sufficiently contribute to supporting Low-Income program funding, and furthermore was slightly subsidized by the Residential sector. The Division is working with Program Administrators and key stakeholders to identify and target further opportunities for energy efficiency investments in the Residential sector to ensure a greater equitable allocation of funds.

5.0 Balancing Short- and Long-Term Savings Objective

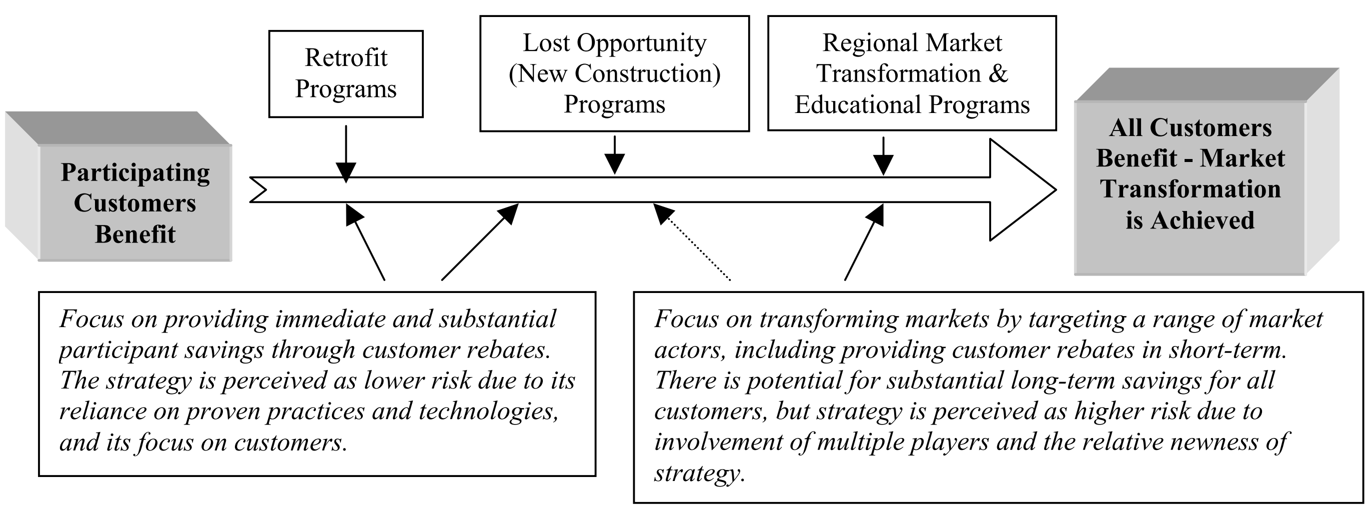
5.1 Types of Energy Efficiency Programs

Ratepayer-funded energy efficiency programs are intended to serve two fundamental purposes: to provide immediate savings for participating customers, while also laying a broader foundation for future savings for all customers through the development of competitive energy efficiency markets. This latter objective requires that programs be designed to tackle existing market barriers to the competitive market for energy efficiency products and services to all classes of customers.

Removing barriers to the use of energy efficient products and services helps to change – or transform – those markets so that a more fully competitive market develops in the future. Thus, "market transformation" is not a label that uniquely identifies certain energy efficiency programs at the exclusion of others. Rather, market transformation is an objective that all energy efficiency programs have the potential to achieve, to at least some extent. While some programs are designed to accomplish specific market changes, others may have effects on markets without necessarily targeting those effects as a program objective.

Market transformation may be thought of as a continuum along which energy efficiency program designs fall. The major types of energy efficiency programs offered in 2000 were Retrofit programs, Lost Opportunity (or New Construction) programs, and Regional Market Transformation programs (which are coordinated with other states in the region). These program strategies span across this market transformation continuum, as shown in Figure 2.

Figure 2. Market Transformation Continuum



A summary of the program strategies that fall along the market transformation continuum is provided in Table 11.

Table 11. Summary of Program Types

Program Type	Short-term Energy Savings	Long-term Energy Savings
Retrofit Programs (or In-Home Services)	Substantial immediate energy savings and cost reductions to participating customers, primarily through the provision of rebates.	Programs have long-term savings impacts over the life of the conservation measures installed. However, savings beyond the life of the measures may not be achieved if markets have not been transformed.
Lost Opportunity (or New Construction) Programs	Substantial immediate energy savings and cost reductions to participating customers through the provision of rebates.	Programs have long-term savings impacts over the life of the conservation measures installed. Savings beyond the life of the measures may be achieved as a result of changing standard building practice and upgrading building codes and standards.
Regional Market Transformation	Some immediate savings for participating customers through rebates, but these ramp-down as energy efficient product market begins to transform.	Potential for long-term savings is large if technology markets are successfully transformed, thus benefiting not only participating customers, but all customers.
Educational Programs	Focuses on increasing customer awareness about energy efficiency products, and helping customers understand how they can reduce their electricity bills. Difficult to quantify energy savings in short-run.	Focuses on increasing customer awareness about energy efficiency products, and helping customers understand how they can reduce their electricity bills. Difficult to quantify energy savings in long run.
Other Programs (e.g., Load Management Programs)	Helps customers achieve immediate savings by shifting electricity use to less costly periods of the day, or paying credits to customers for interrupting service during capacity shortage and emergency periods.	Historically, load management programs have helped to reduce demand for electricity, and thus costs to all customers over time by postponing the need to build new generation capacity.

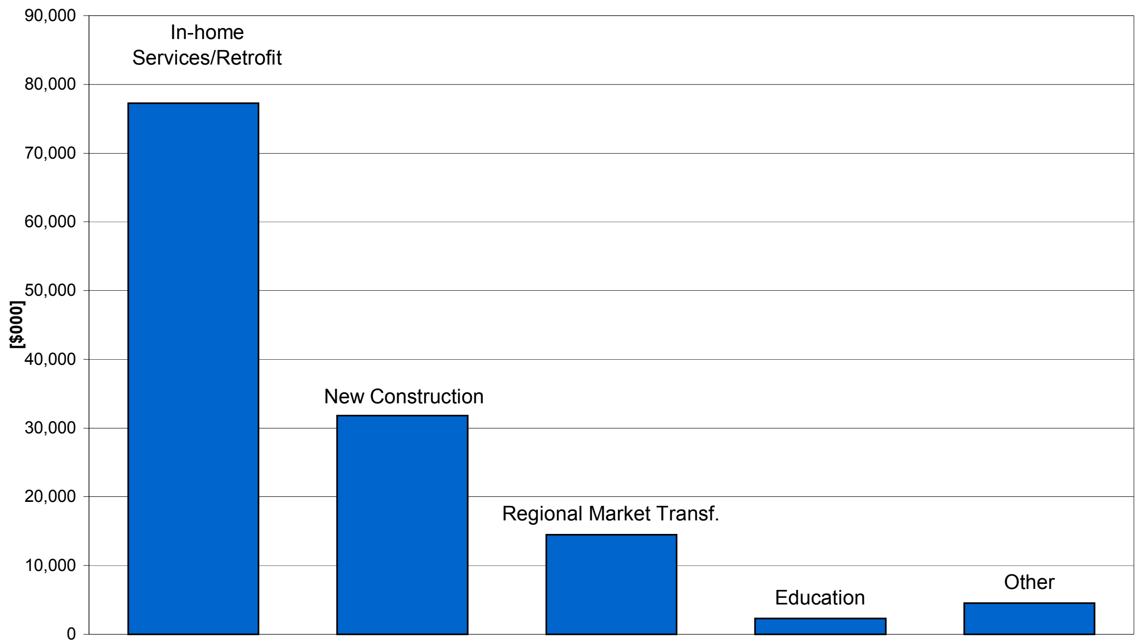
5.2 2000 Program Expenditures/Savings by Program Type and Customer Sector

In 2000, a total of $130.5 million of ratepayer-funds was invested in Program activities. The majority of these investments was in Retrofit programs, representing 59 percent of all program expenditures, while Lost Opportunity (New Construction) programs represented about 24 percent of total expenditures. Funding for Regional Market Transformation programs was 11 percent in 2000, while Educational and Other Program expenditures were 2 percent and 4 percent of total expenditures, respectively.

Figure 3 summarizes program spending by the types of programs discussed above. Table 12 further summarizes 2000 expenditures[29] and savings by program type and customer sector.

[29] Expenditures reported in Table 11 include *all* 2000 energy efficiency expenditures, including administration, marketing, program implementation, program evaluation and performance incentives paid to the distribution companies.

Figure 3. 2000 Allocation of Expenditures by Program Type



Source: 2000 Compilation of Program Statistics, Division of Energy Resources

Table 12. 2000 Expenditures and Savings by Program Type and Customer Sector

Customer Sector	Program Expenditures		Program Savings		
	Million $	% of Total	Annual (million kWh)	Lifetime (million kWh)	Lifetime % of Total
Low-Income					
In-home Services	$13.3	10%	19	273	7%
New Construction	0.9	1%	0.5	12	
Subtotal	***$14.2***	***11%***	***19.5***	***285***	***7%***
Residential					
In-home Services	$11.0	8%	14	190	5%
New Construction	$4.2	3%	.5	13	0%
Regional Market Trans.	$12.2	9%	38	388	9%
Info. & Education	$2.3	2%	2	11	0%
Other	$0.7	1%	0	0	0%
Subtotal	***$30.4***	***23%***	***54.5***	***602***	***15%***
C&I					
Retrofit	$53.1	41%	122	1,962	47%
New Construction	$26.7	21%	70	1,236	30%
Regional Market Trans.	$2.3	2%	7	63	2%
Info. & Education	$0	0%	0	0	0%
Other	$3.8	3%	0	0	0%
Subtotal	***$85.9***	***66%***	***199***	***3,261***	***79%***
TOTAL	**$130.5**	**100%**	**273**	**4,147**	**100%**

Summary: Balanced Savings Objective

A balanced portfolio of programs should ensure immediate savings to participating customers, while also providing for the transformation of energy efficiency markets on a permanent basis. This essentially requires that programs, where possible, be designed to leverage non-ratepayer funded activities. The extent to which ratepayer funds are able to leverage private funds is an important indicator of success in transforming energy markets.

The portfolio of program strategies in 2000 did not change dramatically relative to 1999. For the Residential sectors, the most significant changes occurred with greater investments being made in Regional Market Transformation programs, and increased investments for Low-income customers, both of which the Division views as positive trends to helping effectively transform energy efficiency markets.

For the C&I sector, the majority of funds continued to focus on Retrofit programs, followed by Lost Opportunity programs – all of which provided participating customers with substantial and important immediate savings. Although these program activities contributed to long-term energy efficiency market change, the Division recommends that more emphasis be placed on evolving Retrofit and Lost Opportunity programs so that they bring about permanent changes to energy efficiency markets, thus benefiting all C&I customers. Specifically, the Division recommends that they:

- Be designed to leverage private-sector activities more aggressively;
- Focus on trade ally education; and
- Be coordinated with Regional Market Transformation programs to the greatest extent possible so that energy efficient product markets can be transformed more effectively.

Furthermore, as experience with Regional Market Transformation programs demonstrates quantifiable changes in market share for specific energy efficiency technologies, funding for these types of programs should be expanded.

Finally, the Division recommends that, with increasing concerns about system reliability issues, Program Administrators should place greater emphasis on designing certain residential and C&I programs to specifically address the goal of reducing electric energy use during peak demand periods. This is especially critical during peak summer hours when electricity demand is typically at its highest, and the system can become seriously constrained. The Division is working with Program Administrators and key stakeholders to further explore this issue.

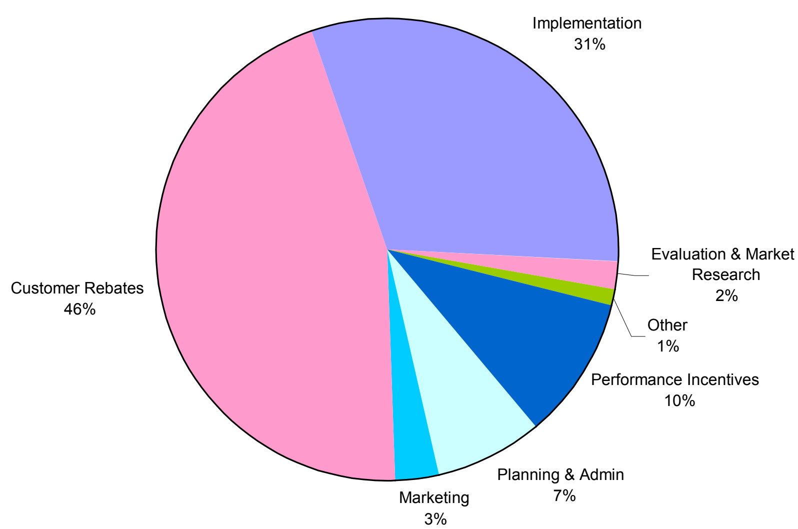
6. 0 Development of Competitive Market Objective

The Division continues to observe a lack of energy efficiency services offered by competitive retail suppliers. This appears to be largely due to limited activity in the electricity market in general, but also due to certain barriers customers face (e.g., paying for up front costs of energy audits) to investing in energy efficiency.

While little or no progress was made in increasing competition for energy efficiency services through competitive retail suppliers, another measure of competition in the energy efficiency market is the extent to which ratepayer-funded program services (e.g., program implementation) are competitively procured. The Act requires that competitive procurement processes be used to the greatest extent practicable when delivering programs to Massachusetts' customers. These procurement processes benefit customers by providing lower, competitively set program costs, as well as by introducing innovative elements to program designs and/or implementation.

Competitive procurement processes are typically utilized by Program Administrators to obtain services in some aspects of program administration, program marketing, program implementation, customer rebates, and program evaluation. In 2000, these cost categories represented 90 percent of total ratepayer-funded energy efficiency expenditures, as shown in Figure 4. Only the 10 percent of costs for performance incentives (those rewards earned by the distribution company for achieving specific program performance goals) and most internal administrative expenses are not subject to competitive procurement.

Figure 4. 2000 Electric Distribution Company Expenditures by Cost
Total = $ 130.5 million



Source: 2000 Compilation of Program Statistics, Division of Energy Resources

Of the $130.5 million spent on Program activities in 2000, $104.4 million (or 80 percent) was spent on services contracted through energy efficiency service providers, as shown in Table 13. Further, most of these contracted services ($95.3 million or 73 percent of total 2000 expenditures) were secured through a competitive procurement. The majority of these competitively procured services were related to customer rebate related expenditures, followed by program implementation, evaluation, and marketing. Program administrative costs and performance incentives account for the remaining 20 percent of total expenditures that was not competitively procured. On balance, the provision of ratepayer-funded energy efficiency services in 2000 relied substantially on competitive procurement processes, and was relatively unchanged from prior year performance.

Table 13: Procurement of Ratepayer-Funded Energy Efficiency Activities (Percent of Total Expenditures = $130.5 million)

Cost Category	Internally Expended Activities	Contracted Out Services		Total Expenditures
		Comp. Procured	Not Comp. Procured	
Rebates to Customers	0%	45%	0%	45%
Implementation	1%	24%	6%	31%
Performance Incentives	10%	0%	0%	10%
Administration	7%	0%	0%	7%
Evaluation	1%	1%	0%	2%
Marketing	0%	3%	0%	3%
Other	1%	0%	0%	1%
Total	**20%**	**73%**	**6%**	**100%**

Note: Percentages may not add up due to rounding.

APPENDICES

Appendix A: 2000 Electricity Bill Impact Analysis Methodology

The Division's 2000 energy efficiency bill impact analysis consisted of two parts. First, the Division analyzed the bill impact of energy efficiency program energy (kWh) savings for participating customers by key customer segments: Low-Income, Residential, and Small, Medium and Large C&I. This involved estimating the average annual energy charges that participants avoided as a result of energy savings due to energy efficiency equipment installations in 2000. These estimated avoided charges were based on the *variable* portion (i.e., $ per kWh) of the tariff for each rate class for each electric distribution company.

Second, the Division performed a bill impact analysis of the total avoided annual demand (KW) charges due to energy efficiency programs for those participants with such a component on their electricity bill. The calculation of avoided annual demand charges was based upon a state weighted average demand charge for demand savings over the year.

1. Energy Savings Bill Impact Analysis

Calculation of Avoided Energy Charges. Avoided energy charges (i.e. charges based on kWh consumption) over the period of 2000 were estimated for each distribution company by adding up all variable charges (i.e., not including fixed charges such as the customer charge) for each rate class, and then weighting the avoided charges by the number of months they applied during the year. (This weighting was necessary because all distribution companies had at least one rate change during the year and some companies had two.) Thus, the resulting rate was a weighted average of the avoidable energy charges by rate class for each distribution company.

Estimate Average and Total Annual Bill Savings. Using energy efficiency program energy savings data for each rate class (provided by the distribution companies), the Division estimated average annual bill savings by multiplying the savings for each rate class by the avoidable energy charge for that rate class. The total of these bill savings was estimated to be more than $19 million, as follows:

> Total Annual Bill Savings = Σ (S*AEC), where:
> S = kWh savings from programs by rate class for each distribution company
> AEC = Weighted avoidable energy charge by rate class for each distribution company

The Division aggregated the results for the rate classes for each distribution company into the following customer segments:

1) Low-Income
2) Residential
3) Small C&I - rate classes with average monthly use of less than or equal to 3,000 kWh/month.
4) Medium C&I - Medium C&I includes rate classes with average monthly use greater than 3,000 kWh/month, but less than or equal to 120,000 kWh/month
5) Large C&I - rate classes with average monthly use greater than 120,000 kWh/month.

Total bill savings for each rate class were also divided by the number of participants reported by each distribution company to determine the average bill savings per participant.

Average Bill Reductions as a Percent of Total Average Annual Bills. In order to determine the average percent reduction on an average annual bill, the Division first calculated average annual bills for each rate class (using average annual usage values per participant, as provided by the Program Administrators).[30] Two bills were then calculated for the purpose of comparison, an average annual bill per participant *with* the program, and a hypothetical average annual bill per participant *without* the program. The average annual bill per participant *without* the program was found by first adding actual kWh usage per participant to kWh savings per participant, based on the assumption that the usage savings would have been used were it not for the program in place. This number was then multiplied by the avoidable energy charge and added to the fixed (i.e., non-variable) charge for the year. The average annual bill per participant with the program was found by multiplying actual kWh usage per participant by the avoidable energy charge and adding that to the fixed charge for the year. The difference between the two was then considered average annual bill impact and the percent reduction was calculated.

Similar to the process for estimating the average and total annual bill savings, the Division aggregated the results of its analysis into the customer segments described above.

2. Demand Charge Bill Impact Analysis

The Division's analysis of the demand charge bill impact for participating customers involved the following steps:

- Estimating a weighted average demand charge for each distribution company. This required multiplying the total demand charge (i.e., charge per kW peak in a billing cycle) per rate class by the number of participants in that rate class, adding across all rate classes for each distribution company, and dividing by the total number of participants for each company.
- The total company weighted average demand charge was then aggregated by adding the company-weighted averages together and dividing by the total number of participants for all companies. The total weighted average demand charge was estimated to be $6.54 per KW.
- The total weighted average demand charge was multiplied by demand (KW) savings that accrued to C&I participants that were on a tariff with a demand charge. These average demand savings of 15,773 (not including interruptible credit program savings) were based on summer/winter peak savings for all hours as reported by Program Administrators, and reflect average savings weighted over summer months (5), and winter months (7). The Division's analysis assumed that individual customer peaks were coincident with system peak.

[30] For the Small and Medium C&I sectors, respective average annual bills were based on the average of 1999 and 2000 average usage data. For both sectors, available data for average usage reflected usage across the entire *rate class* (as opposed to average *participant* usage). This data, used to estimate the average participant bill, can distort the bill impacts in terms of percent bill savings, especially for the Small and Medium C&I sector given that average usage across these sectors can vary considerably. As such, 1999 and 2000 data were averaged in order to provide a more realistic average bill per participant value. The Division is working with Program Administrators to correct this data problem in future reports by requiring that average participant usage data be tracked and provided.

- The 15,773 in kW savings resulted in roughly $1.2 million in annual bill savings to participating customers, as shown in the table below.[31]

	Total C&I kW Savings	Less Interruptible Credit Program kW Savings	kW Savings Weighted Over Summer/Winter Months
Summer Peak Savings	73,733	35,808	14,920
Winter Peak Savings	57,979	28,084	16,382
Avg. KW savings			15,773
Avg. $/KW monthly rate			6.54
Monthly Savings			$103,156
Annual Savings			**$1,237,867**

[31] Note that the demand bill savings for 1999 C&I participants were incorrectly calculated. The total savings, which were reported as $5.1 million, were overstated and should have been reported as $2.6 million.

Appendix B: Wholesale Energy Clearing Price Impact Analysis

The Division's analysis of how ratepayer-funded energy efficiency programs can reduce wholesale energy market clearing prices involved two major steps. First, peak summer savings values provided by distribution companies were adjusted in order to aggregate them and extend them over a greater number of hours. Second, price impacts were calculated using ISO-NE day-ahead bidstack data. This second step involved the specific mechanics of pinning day-ahead bids to actual price and load measures, as described below.

The Division's analysis focused on three price impact scenarios:

- June 27th - 13 hour peak period 8am-9pm
- Summer months June-September of year 2000 due to 2000 program installations; and
- Summer months June-September of year 2000 due to 1998-2000 program installations.

For each of the above scenarios, the Division calculated average peak summer savings and price impacts using the methodologies described below.

A. Peak Savings Estimates

Massachusetts distribution companies estimate summer and winter peak demand reductions (peak savings) as a result of their energy efficiency programs. These estimates are coincident with system peak. As such, the values reported by the companies do not reflect peak load savings for every hour, but rather for a set of conditions intended to be representative of the time of the peak load. In order for the Division to analyze spot price impacts for other times during the summer, it first analyzed cooling-related savings. Specifically, a set of estimates of the kW load reductions for cooling-related measures or programs was derived for each hour of the period analyzed to reflect the approximate weather sensitivity of cooling efficiency measures.[32] This involved the following steps:

1. For weather-sensitive (e.g., cooling) loads, the assumption of a flat peak kW impact across the widest definition of peak hours would be inaccurate, since impacts vary radically both within and across days. Therefore, the Division developed estimates of the hourly reduction in the New England system load due to the energy efficiency programs.

2. The utilities peak savings data was integrated using a reference load shape derived from the Independent System Operator - New England (ISO-NE) system load itself. Average hourly load for the shoulder months April and October were calculated as an estimated non-cooling load base. This non-cooling load base was removed from the system load over all summer hours. The remaining load shape represented cooling load within ISO-NE.

3. A utility specific average peak cooling load was calculated from this cooling load reference shape. This was done by averaging the system cooling load over the hours that define each utility's peak hours. Average peak cooling load at NSTAR, for instance, was calculated by

[32] For non-cooling measures it would likely be acceptable to compute a total by simply summing peak kW savings across all the utilities. However, cooling savings are a significant fraction of peak load savings.

averaging system cooling load over the hours 8am to 9pm, from June through September. WMECo's peak was defined by a single hour. The cooling load at that hour is their average peak cooling load.

4. The average peak cooling load for each utility was used to scale the original system cooling load shape. This was done by dividing each hourly load by the respective utility's average peak cooling load. These scaled shapes essentially consisted of a set of hour-specific ratios that in turn scaled utility-specific estimates of average peak cooling load savings to hourly measures that are comparable across utilities.

5. The estimates of utility peak cooling load savings were calculated from utility estimates of energy savings. Cooling load savings are a percentage of HVAC program energy savings.[33] MWh were converted to MW using results from a 1993-4 Cambridge and Commonwealth Electric load model of Commercial and Industrial cooling. Commercial and Industrial cooling represented almost 90 percent of the estimated cooling savings.[34]

6. The resulting estimates of utility specific average cooling load savings were then converted to hourly measures that could be summed for each hour across utilities. This created a combined variable estimate of cooling load for each hour. The non-cooling related energy efficiency savings, those that remained after pulling out the variable cooling load from each utility, were then added to the hourly cooling load for a total hourly savings measure.

B. Price Impact Calculations

There is substantial inherent uncertainty regarding which generator would have set the energy clearing price (ECP) on the margin if the system load had been higher (that is, without the state's efficiency programs). This is primarily due to the fact that some generators, after submitting their price bids on one day, may become unavailable to run on the next day, so that a different generating plant, having bid a different price, may actually be dispatched to meet load (thereby setting the ECP) in any particular hour.

For the price calculations, a model developed by XENERGY was used based on a data set with the following variables for every hour of the period from June 1 through September 30, 2000:

- the actual ECP clearing price;
- the actual NE system load; and
- the "bid stack" of prices that increase for each "step" in generating capacity that could be brought on line to meet system load for that hour.[35]

[33] Table 6A "2000 MWh Savings by End Use (generator level)"
[34] MWh of usage (energy savings) per MW of capacity (or peak reduction) were estimated to be 1,846 and 1,535 for Cambridge and Commonwealth, respectively. For the utilities for which actual MWh per MW estimates were not available, a conservative ratio of 1,500 was used.
[35] The existing model was enhanced for this DOER analysis by introducing the ability to input a different bid stack for each hour, and downloading the actual bid stack values for the summer of 2000.

These data are available from ISO-NE at:

http://www.iso-ne.com/historical_bid_data/,

http://www.iso-ne.com/forecasted_vs_actual/,

http://www.iso-ne.com/historical_market_data/energy_spot_market/.

The input to the price impact model was a series of estimates of the additional load in each hour that the New England system would have had to serve absent the energy efficiency programs.

The model calculated the price differential that would have resulted in each hour from that additional load. The price differential generated by the model is actually the difference between the closest bid price below the actual clearing price and the price of the bid needed to cover the additional load.[36] The results of the Division's analysis are as follows:

Scenario 1: June 27, 2000, 13 Hour Peak Period Impact

The Division first analyzed the impacts of energy efficiency programs over the peak hours of the day (8am to 9pm) on June 27, 2000. In hour 13 of that day the load reached 21,916 MW and prices reached $343.80 per MW. During this day, the energy efficiency measures installed under the utility efficiency programs reduced the load an average of 72 MW. The end-users participating in those energy efficiency programs reduced their consumption, and thereby their electric bills (based on their retail prices). But in addition, the programs helped to reduce wholesale electricity prices that were ultimately passed on to other customers on the system.

Without the 72 MW reduction attributed to the energy efficiency programs, additional generating units would have been needed to meet the system load. Based on the generators that submitted the next few higher price(s), the average energy clearing price (or "ECP") would have been **$101 per MWh** without the energy efficiency programs. This constitutes a savings of **$10 per MWh** from the average of price bids submitted by the generating unit that was lower in the "bid stack" by the hourly load savings amount. The data on which this analysis is based is not sufficient to confirm that the units having bid these prices were *actually* at the margin in that hour, or would have been at the margin without the effect of the efficiency. Nevertheless these data indicate a potential **$393,483** in savings to the buyers in the spot market during the 13th hour peak period on June 27, 2000.

Scenario 2: Summer 2000 Impact Due to 2000 Measure Installations

Over all peak hours of the summer of 2000, the energy efficiency measures installed under the utility efficiency programs reduced the load an average of 48 MW. Without the 48 MW reduction, additional generating units would have been needed to meet the system load. The average "ECP" would have been **$.5/MWh** higher without the energy efficiency programs. This difference from the price bid submitted by the generating unit that was, on average, 48 MW lower in the "bid stack," appears small. However, given that this price impact is reflected in every peak hour of the summer 2000, these data indicate a potential **$2,202,894** in savings accrued to spot market buyers, and ultimately, their customers.

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[36] The specifics of the bidstack methodology are discussed later in this Appendix.

Scenario 3: Summer 2000 Impact Due to 1998-2000 Measure Installations

The analysis of the cumulative impact of three years of installations is similar to Scenario 2 above in that it is performed over all summer peak hours during year 2000. However, because the peak savings estimate in Scenario 2 was only performed for summer 2000, a slightly different approach was used in this scenario to estimate savings attributable to energy efficiency installation over the three years 1998-2000. In the absence of variable hourly savings load for the two previous years (1998-99), the Division's analysis relied upon simple totals of utility savings estimates for the total savings for each year's installations. This necessitated conducting the analysis with a flat savings impact across each hour of the summer. To minimize the effect of both the use of simple totals and a flat impact, the analysis was run on summer 2000 data with a flat savings impact with the intent of approximating the spot market value of the variable savings load analysis. A flat savings impact of 55 MW, slightly higher than the simple total of 51 MW, was actually needed to produce results similar to the summer 2000 variable load analysis spot market results. The 1998 and 1999 simple totals were also scaled up by this ratio (to 54 and 58 MW, respectively), and then the three flat impacts were totaled. Using this approach, the three years savings were approximated at 167 MW of flat savings.

Without the cumulative three-year impact of 167 MW, the average "ECP" would have been **$1.3/MWh** higher in every peak hour of summer 2000. These data indicate a potential **$5,724,291** in savings to the buyers in the spot market over the summer of 2000.

C. Bid-Stack Methodology

The use of the ISO-NE day-ahead bid-stack data is relatively straightforward. However, how the day-ahead bid-stack is pinned to reality requires some explanation to better understand the mechanics of the Division's above analyses.

ISO-NE provides a list of MW amounts and bid prices. Bids for the same dollar amount are combined and these combined bids are ranked from lowest to highest. The result is a set of variable size stairs rising from left to right as load and price increase. As stated before, the day-ahead bid stack does not exactly represent the actual real-time supply curve. The actual load and price points available on an hourly basis from ISO-NE do not land on the day-ahead stack for that hour. The stack must be shifted left or right so that actual load and price coincide with the stack.

Because actual prices are rounded to the nearest cent and bids are made in round dollars, a right-left shift will always coincide with the vertical part of the stair. However, in terms of the bid stack this is not a point that represents a realistic price-load combination. A price between two bids indicates that the more expensive generation has not yet been activated. The solution is to drop to the nearest stair (load-price combination) below the actual price.

Because the analysis is based on a relative shift of load it is also important to consider where on the stair (multiple MWs of load bid at the same price) the actual load should be pinned. Simply dropping to the stair below from the initial meeting point on the vertical is problematic. The analysis compares this point to a point to the right representing the assumption of greater load without energy efficiency savings. If the starting point is always the last MW of load available on the lower stair then even a single MW of savings will have a minimum one dollar price differential in every hour. A more conservative approach shifts the bid stack so that actual load coincides with the midpoint of that first stair below. Under this assumption there will only be a price change if the stair is less than twice as wide as the assumed load savings. This maintains the very real potential that a small decrement of load will in fact have no impact on prices.

Appendix C: Job Impact Analysis – REMI Model Overview and Assumptions

The Division used the REMI Economic and Demographic Forecasting and Simulation Model (REMI-EDFS) to determine the economic impacts of ratepayer-funded energy efficiency programs over time in the state of Massachusetts. The REMI-EDFS model, calibrated for the state of Massachusetts, is used in this study to represent the economic impacts over time, resulting from 2000 spending on energy efficiency programs.

The model integrates the key aspects of three economic modeling tools: (1) Input-Output (I-O) models; (2) Computer General Equilibrium (CGE) models; and (3) Econometric models. In general, it is able to forecast over 2000 output variables for the years 2000 to 2035 using a historical database that spans the years 1969 to 1998. However, in this study, the Division examined only three of these outputs over the forecast horizon through the year 2010: employment, as measured by number of employee-years; gross regional product (GRP), which provides an overall measure of economic production in the Commonwealth; and disposable income, which is the income (after taxes) that results from this increased economic activity.

1. Overall Methodology. The REMI model first calculates a baseline forecast for the state of Massachusetts using historical data and the most likely scenario for future economic conditions. The analysis then incorporates any changes related to the energy-efficiency programs to the model – via policy variables – in order produce an alternative forecast (or simulation). This part of the analysis relied on Bill of Goods (BOG) data. The BOG data were developed by the Goodman Group, Ltd., and disaggregates energy efficiency expenditures to industry-specific expenditures.[37] The simulation results are then subtracted from the baseline forecast in order to produce the net impact of policy changes.

2. Steps. The REMI model analysis involved the following steps:

a. The Division ran a control forecast and examined the results for the outputs of interest.
b. Based upon 2000 energy efficiency expenditure data (including investments using ratepayer funds and participant costs), the Division established the amount by which each policy variable should be changed. This involved use of the BOG data to allocate energy efficiency expenditures to the relevant industries of the Massachusetts economy. As described below, changes in these industries' demands were input as policy variables to REMI.
c. The Division reran the model. A complete alternative forecast was created based on the policy variable changes.
d. The Division interpreted the impact of policy change by analyzing the differences between the alternative and the control forecast.

3. Policy Variables. The following policy variables were used to model expenditures on energy-efficiency products and services:

[37] For efficiency technologies, BOG data were principally derived from Massachusetts utility accounting records, which incorporated all aspects of costs (program administration, overhead, labor, and consulting services, as well as materials and equipment).

a. Increased demand for mining industry products/services. This variable includes spending on windows, insulation, solar water heating, lamps, lighting fixtures, heating, ventilation and air-conditioning (HVAC) controls, heating & cooling equipment, refrigeration, and motors.
b. Increased demand for rubber industry products/services. This variable includes spending on plastic products.
c. Increased demand for stone, clay, and glass products/services. This variable includes spending on mineral products.
d. Increased demand for machinery and computer equipment products/services. This variable includes spending on metal working, special industry, and general industry products.
e. Increased demand for railroad, trucking, air transportation, public utilities transportation, and other transportation industry services.
f. Increased demand for wholesale trade services.
g. Increased demand for professional and business services.

4. Results. The table below shows the results of the Division's REMI simulation. The employment impact is further broken down by industry sector.

Key Results	**2000**
Gross State Product (million of 2000$)	73
Disposable Income (million of 2000$)	48
Number of Jobs Created By Sector	
Agriculture	5
Mining	10
Construction	108
Durable Goods	170
Non-durable goods	15
Transportation	34
Finance, Insurance, and Real Estate	43
Wholesale	94
Retail	136
Services	552
State & Local Government	16
Total Employment (employees)	1,183

5. Interpretation of Results. 2000 energy efficiency program activities generated an estimated 1,183 net new jobs in Massachusetts in 2000, contributing $73 million to the gross state product (GSP). In addition, $48 million in disposable personal income was gained from these jobs, concentrating in the services, retail trade and manufacturing sectors. The impacts of 2000 ratepayer-funded energy efficiency activities on the Massachusetts economy occur over time. As expected the greatest impact is in the first year. Subsequent impacts (e.g., over a ten to fifteen year period) are lower as the increased demand from energy efficiency products is met. It is important to note that employment figures represent employee-years. Thus, future job impacts due to 2000 expenditures are not additional, “permanent” jobs created, but rather are jobs that remain in future years that were originally created in 2000. The largest employment sector is services and durable goods, followed by retail and construction – a result due to the nature of the energy efficiency products and the local economy. The $73 million in GRP provides an overall measure of economic production in the Commonwealth due to 2000 energy efficiency expenditures. Finally, as a result of 2000 activities, the Division estimates that $48 million in disposable income was created, which is the income (after taxes) that results from this increased economic activity. As with employment, the GSP and disposal income figures decline over time.

Appendix D: Air Emission Reduction Analysis

The Energy 2020 model was used to analyze the emission reduction impacts of the energy efficiency programs. The Energy 2020 model is an integrated energy model that contains detailed demand and supply sector simulations, including macroeconomic interactions as supplied by the REMI model (see Appendix C). The model is maintained by Systematic Solutions, Inc., and has been used extensively by over 50 utilities and states/provinces in both deregulated and transitioning environments. More recently, Energy 2020 has been used to examine the regional impacts of proposed Kyoto initiatives at the national level.

1. Results of Energy 2020 Analysis

The Division's 2000 analysis of emission reductions used the Energy 2020 model to examine the impacts of energy efficiency programs on the price to generate electricity, which in turn impacts the decisions about the dispatch, building of capacity, and exports and imports of electricity to other regions. The model focuses on how energy efficiency programs reduce electricity demand, which in turn leads to a reduction in the overall price for electricity. This reduction in price can be quite dramatic when energy efficiency programs reduce peak demand. A reduction in price, while positive, can also produce disincentives for more expensive (and cleaner) plants, such as new combined cycle gas plants, to be dispatched or built. This occurs because reductions in price lead to reductions in revenues (current and anticipated), which results in reduced investment and dispatch in more expensive technologies.

The results of the model showed that a displacement of plants (according to fuel type) occurred in the following fashion in 2000 due to the 2000 energy efficiency program related energy savings of 273 million kWh: 51% gas/oil steam, 7% coal steam, 14% gas/oil combined cycle, and 28% gas/oil turbines. The associated emission reductions in 2000 were 705 tons of nitrogen oxides (NO_X), 1,405 tons of sulfur dioxides (SO_2), and 253,100 tons of carbon dioxide (CO_2).

The Division also estimated the emission reductions over the lifetime of measures installed in 2000, or over the period 2000-2014. Total savings over this period were estimated to be 4,147 million kWh, which over the long-term will reduce emissions as follows: 6,558 tons of NO_X, 9,086 tons of SO_2, and 2,042,400 tons of CO_2. This analysis assumes no retirement of plants over the period 2000-2014, and the addition of 7,200 MW of new combined cycle gas/oil units (dual and single fuel, primarily gas with oil back up) that are anticipated to come on line before 2002.[38]

2. Key Model Characteristics/Assumptions

The major assumption underlying the Energy 2020 model work is to use historical data (up to 1998) for model calibration. This is important given the recent dramatic changes in the energy environment since then, such as the higher oil and gas prices. This database essentially describes the "assumptions" underlying the model. However, the model's results are not completely traceable to these assumptions given the complexity of the internal system interactions.

[38] See ISO 2001 Regional Transmission Expansion Plan.

In order to somewhat simulate recent changes (and include an important assumption that has major impacts on results), the Division ran the model in a higher-gas environment than was previously expected using the existing historic data. Additional corrections, such as knowledge of particular generation expansions not forecasted in the model are also possible and will be included in future analyses.

A second important assumption applied in the Division's analysis was the use of deregulated decision-making in terms of dispatch and capacity addition. Dispatch and generation decisions are made using the following technologies: oil/gas combustion turbine, oil/gas combined cycle, oil/gas steam turbine, coal steam turbine, advanced coal, nuclear, baseload hydro, peaking hydro, renewables, baseload purchase power contracts, baseload spot market, intermediate purchase power contracts, intermediate spot market, peaking purchase power contracts, peaking spot market, and emergency purchases.